Final Report to

RPSEA
Research Partnership to Secure Energy for America

Mini-Waterflood: A New Cost Effective Approach to Extend the Economic Life of Small, Mature Oil Reservoirs

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Dr. Thomas W. Engler
Telephone Number: (575) 835-5207
Facsimile Number: (575) 835-5210
e-mail address: engler@nmt.edu

New Mexico Institute of Mining and Technology
801 Leroy Place
Socorro, NM 87801 USA
www.nmt.edu

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Principal investigator: ____________________

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ABSTRACT

The purpose of this project was to improve oil recovery and extend the life of the Round Tank (Queen) reservoir. Based on this knowledge, the second step was to provide a mini-waterflood design, applicable and transferrable to other Queen fields with similar field/reservoir conditions. Two wells were drilled, one injector and one producer, for a pilot waterflood pattern. A core obtained from the producer was analyzed to obtain petrophysical properties and displacement performance. A key finding was evidence of fines migration and clay swelling in the core. The consequence is rapid reduction in permeability during water injection.

The petrophysical properties from the core were included in a full field reservoir characterization and simulation study to determine a strategy to develop the entire field. Successful characterization of the Round Tank Queen reservoir with limited and poor quality data was accomplished with the assistance of modern logs and core analysis. A newly discovered friable sand bed was identified and has implications on stimulation effectiveness and reservoir performance. The results from history matching show satisfactory outcomes; a minor adjustment was made for the porosity distribution, and reservoir boundary was identified; however, a large permeability reduction was necessary for a successful history match, indicating that permeability of the Round Tank Queen formation is significantly lower than the other Queen sands. The prediction results of the proposed flooding pattern show poor performance: low oil production and water injection rates, slow flood front movement and inability to fill-up reservoir pressure. Many factors contribute to the poor performance including low permeability, high oil viscosity, depleted gas-cap and low differential pressure between bottomhole and reservoir.

The variable mechanical properties of the Queen seen in the core and logs, and the presence of clays and fines migration, have implications on both hydraulic fracturing and water injection. For this reason, an investigation into the stimulation effectiveness of the injection well was initiated. The treatment failed mostly because the created fracture was horizontal intersecting a vertical well (Pan Cake fractures), with a very small propped width. In addition, the compressible friable sand layer acted like a sponge; i.e., compressing when adding pressure (or force) but not cracking to create length needed for fracturing. As a result the energy of the fracture treatment was diverted to the lower quality Queen layers or dissipated after the treatment.

The failure to achieve injectivity resulted in no increase in reservoir energy or improvement in sweep efficiency; and thus no improvement in oil recovery. However, on a positive note, we have added to the knowledge-base to assist others with similar challenges; particularly obstacles to overcome.

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EXECUTIVE SUMMARY

The purpose of this project was to improve oil recovery in marginal oil plays that have been ignored for secondary and/or tertiary recovery by major producers. Typically these types of reservoirs are limited in extent, poorly characterized, at low pressure and temperature and frequently are shallow discoveries after deeper targets proved non-productive. The Round Tank (Queen) Field in Southeast New Mexico fits all of these criteria and thus was selected to test the feasibility of injecting water and improving oil recovery. Furthermore, the characteristics of this field are analogous to many other Queen fields in the area and therefore knowledge acquired in this work will be applicable and transferrable to other Queen fields with similar field/reservoir conditions.

Two wells were drilled to initiate a pilot waterflood project. A core was acquired in one of the wells and this, along with old logs (circa 1960s), 14 modern logs (obtained from wells drilled to the deeper San Andres Formation) and production data, are the only sources of information for this reservoir study. Details of the reservoir characterization can be found in Srichumsin (2011) and Srichumsin, et al. (2011). Two key findings were the quality of the reservoir rock was poorer than expected and the existence of a friable zone (one-third of the core was recovered in pieces). Petrographic analysis of the core (thin sections and SEM) exhibited significant fines and clays in the pore space, along with anhydritic cement. Poor core injectivity tests confirmed the presence of fines migration (Wilson, 2010).

The petrophysical properties from the core were included in a full field reservoir characterization and simulation study to determine a strategy to develop the entire field. Successful characterization of the Round Tank Queen reservoir with limited and poor quality data was accomplished with the assistance of modern logs and core analysis. Evidence from sonic logs and the core samples resulted in a newly discovered friable zone exists within the Queen sand in the pilot area. Subsequently, mechanical properties vary significantly within this reservoir and have implications on stimulation effectiveness and reservoir performance. A successful history match was achieved after reducing the initial permeability values by approximately two-thirds. The large permeability reduction from history matching indicates that permeability of the Round Tank Queen formation is significantly lower than the other Queen sands since the original permeability was acquired from adjacent field correlations.

The majority of Queen sand wells are hydraulically fractured to increase conductivity. In the Round Tank Field, the variable mechanical properties of the Queen seen in the core and logs, and the presence of clays and fines migration, have implications on both hydraulic fracturing and water injection. For this reason, an investigation into the stimulation effectiveness of the injection well was initiated.

Analysis of the fracture treatment in the new water injection well supports the creation of a horizontal fracture as a result of the shallow depth and the compressible nature of the friable zone resulting in a high fracture gradient, 1.06 psi/ft (Oduye, 2011), and consequently diverting the horizontal fracture to a thin zone within the top of the Queen. The compressibility of the friable sand layer acted like a sponge; i.e., compressing when

adding pressure (or force) but not cracking to create length needed for fracturing. As a result the energy of the fracture treatment was diverted to the lower quality Queen layers or dissipated after the treatment.

Field tests resulted in very poor injectivity into the injection well; a few barrels a day with high surface pressures. This outcome is primarily due to the unsuccessful fracture stimulation as a result of the shallow depth and friable sand layer. Additional stimulation methods were attempted to overcome the restriction; such as adding perforations, stimulating with propellent, and drilling three jetted laterals. After all attempts, no increase in injectivity was observed.

The failure to achieve injectivity resulted in no increase in reservoir energy or improvement in sweep efficiency; and thus no improvement in oil recovery. The prediction results from the simulation of the proposed flooding pattern showed poor performance: low oil production and water injection rates, slow flood front movement and inability to fill-up reservoir pressure. Many factors contribute to the poor performance including low permeability, high oil viscosity, depleted gas-cap and low differential pressure between bottomhole and reservoir. However, without flow and pressure data from the pilot test, the actual displacement performance cannot be modeled effectively.

The initial focus on the Round Tank was on the low pressure and temperature and unfavorable mobility ratio (low viscosity oil and no gas); both characteristic of numerous other Queen Fields in the area. However, the mechanical properties of the sand played a significantly more important role in the completion and subsequent injection and production from the Queen sand. To avoid a repeat, it is recommended to correctly characterize the reservoir, and thus properly design the stimulation treatment. As shown in this work, methods are possible using limited data to identify and describe the reservoir.

The following discussion is divided into the three main tasks of the research; i.e., experimental core analysis, reservoir characterization and simulation, and hydraulic fracture evaluation. Each segment contains an objective, approach or methodology, results and discussion, and conclusions section. And finally at the end is a summary discussion of the work accomplished including the impact to small producers and technology transfer efforts.

1. Experimental Core Analysis

1.1 Objective

The primary focus of the core analysis was to measure oil recovery as a function of pore volumes injected and thus determine if waterflood potential existed. This would lead to the development of relative permeability curves for later use in reservoir simulation. Also desired was petrophysical information of the Queen sand including porosity, permeability and mineralogy.

1.2 Methodology

The unsteady-state method for core flooding was used to gather the relative permeability data in order to expedite the core flooding process. The Johnson-Bossler-Nauman method was employed for calculating the relative permeabilities of oil and water, both for the drainage and the imbibition data. Standard lab procedures were used to determine porosity and absolute permeability.

Permeability values started at unusually low levels and decreased as experimentation for each core continued. In order to investigate whether fines migration and/or clay swelling was taking place within the core, Core #3b was flooded with brine until the permeability remained constant at which time, the flow through the core was reversed. The flow continued in that direction until the permeability remained constant and then the flow was reversed again. This cycle was completed a third time, but reversing the direction of flow did not make a significant difference in the permeability.

Thin sections were made at 1 foot intervals from 1492-1495 ft. to characterize the minerals, clays, depositional environment, and general structure of the Round Tank Queen sandstone. The thin sections were stained blue to show the porosity and yellow for potassium feldspar.

In an effort to further understand the Round Tank Queen rock, SEM (Scanning Electron Microscope) photographs were taken at the New Mexico Bureau of Geology and Mineral Resources. All of the photos were taken using either the SE (secondary electron) imaging, or the BSE (backscattered electron) imaging. The secondary electron imaging shows a 3-D picture of the rock sample, while the backscattered electron imaging mode gives a picture of the mean atomic number within the area being observed. The minerals or elements with higher mean atomic numbers show up in the BSE pictures as lighter and the minerals with the lower mean atomic averages are darker. (New Mexico Bureau of Geology and Mineral Resources, 2008)

1.3 Results and Discussion

Porosity and absolute permeability to brine measurements for Core #2 indicated a porosity of 19.3% and a permeability of 2.6 mD. After flooding the core with brine to determine the absolute permeability, oil was injected into the core. The interstitial water saturation (S_{wi}) was shown to be 43% and the effective relative permeability of oil (k_{eo}) at S_{wi} was calculated as 1.17 mD. Brine injection commenced to develop relative permeability and displacement curves. Calculation of the imbibition relative permeability curves was conducted using the JBN method. The relative permeability curves are shown in figure 1.1.

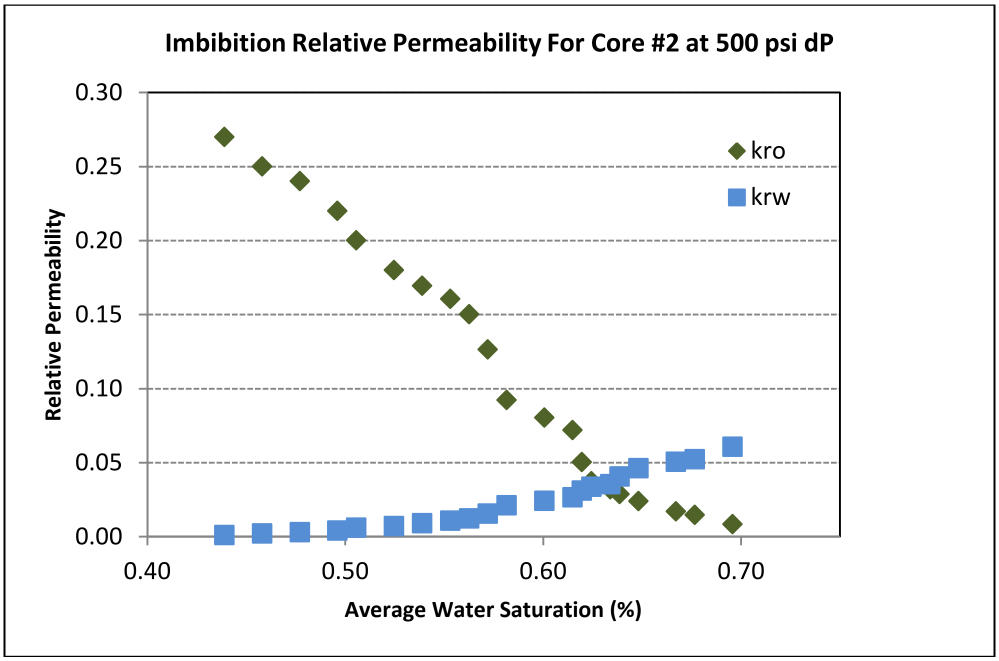

Figure 1.1 Imbibition relative permeability curves for Core sample #2 at 500 psi pressure differential.

The relative permeability curves indicate a strong water-wetting tendency for core #2. Irreducible oil saturation (S_{oi}) is shown to be 31%.

During the core displacement experiments it was observed that the permeability decreased over time. Potential causes for this decrease and the work to eliminate or confirm the cause are listed below. Investigations lead to the conclusion that fines migration (and maybe minor clay swelling) was the culprit.

a. **Incomplete sweep of brine by THF.** In an effort to regain permeability, core #2 was flooded with THF solvent to clean out the pore space after completing a full flooding schedule. The THF exiting the core was completely clear, which indicated that all the oil had been removed. As THF has approximately half the specific gravity of water, the core was rolled 180 degrees to force the THF to float to the top of the core, and remove any remaining brine that would simultaneously be sinking to the bottom of the core. This method did not significantly increase the core's permeability.

b. **Injection fluid contaminants on core ends.** In another effort, core #2 was removed from the core holder and the length decreased by cutting approximately 1.25 cm. off of both ends. If there was any buildup on the face of the injection side of the core, from debris in the oil or brine, or salt deposition, this would remove the obstacle or obstacles to flow. This measure did not alter the response.

c. **Leaks.** During all flow tests a confining pressure of 3500 psi was applied to the core. No changes in confining pressure were observed, indicating a good seal around the core.

d. **Fines migration.** As further investigation was warranted, a fresh plug was cut from the same piece of rock as core #3 and designated core #3b. Rather than clean the pore space with THF, the core was flooded with brine in order to mitigate any effects of the THF. Permeability and cumulative pore volumes injected were recorded to look for the trend displayed in Figure 1.2.

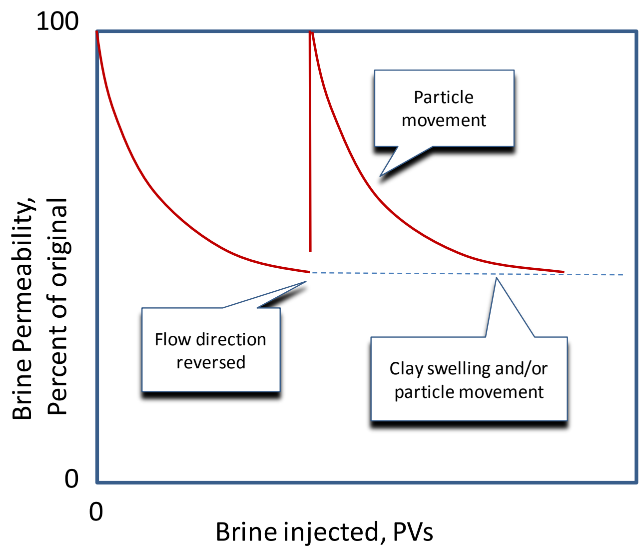

Figure 1.2 Conceptual Permeability Reduction Graph (Core Laboratories Inc.)

The theory behind Figure 1.2 is that injection of fluid from one direction causes the migration of fines or particles through the pore space of the core. These particles travel until they lodge in a pore throat and block the path of fluid flow, which reduces permeability. Reversing the flow of fluid through the core causes the fines to travel in the opposite direction until they lodge in a pore throat elsewhere. This trend is indicated by a sudden increase in permeability when the flow is reversed, followed by a steady decrease in permeability as the fines began to lodge in other pore throats with the continued flow in the opposite direction.

In order to investigate whether fines migration and/or clay swelling was taking place within the core, Core #3b was flooded with brine until the permeability remained constant at which time, the flow through the core was reversed. The flow continued in that direction until the permeability remained constant and then the flow was reversed again. This cycle was completed a third time, but reversing the direction of flow did not make a significant difference in the permeability.

Figure 1.3 clearly follows the same trend as Figure 1.2, indicating fines migration within core #3b. Each time the flow is reversed, the permeability does not go back to its original magnitude. The reduction in the amount of permeability becomes greater every time the flow is reversed. A possible explanation for this is fines within the pore space becoming immobile or clay swelling. This would explain why reversing the flow in core #2 did not increase the permeability as did the flow reversal in core #3b.

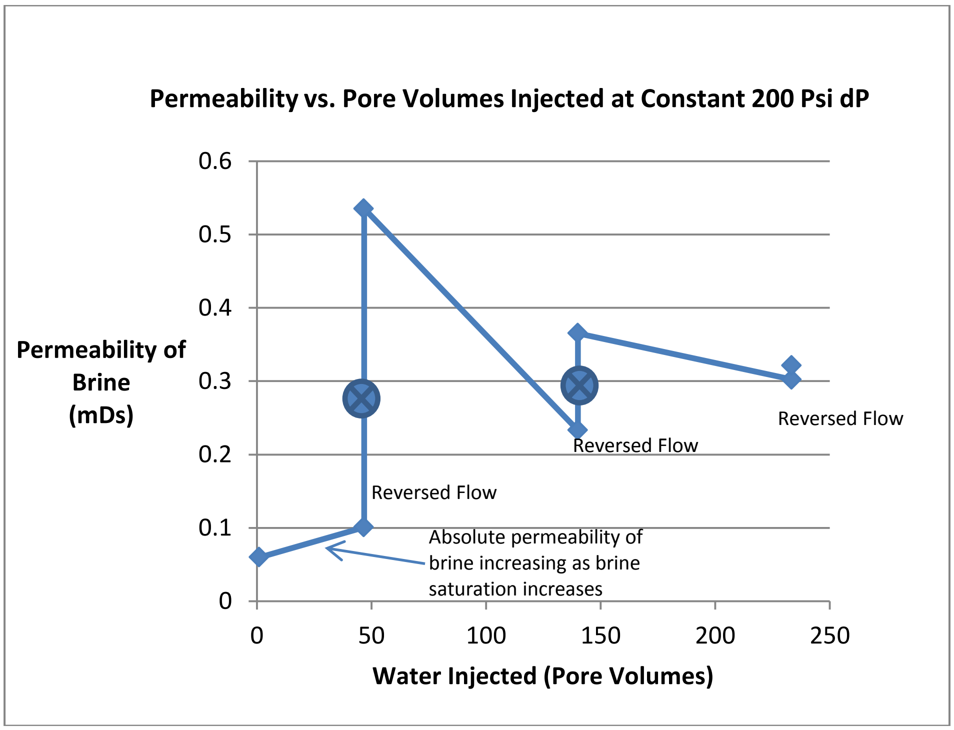

Figure 1.3 Permeability Reduction Graph for Core #3b at 1493.8 Ft.

The calculation of the end point mobility ratio for core #2 was based from Willhite, 1986. The value for k_{rw} is taken at irreducible oil saturation (S_{oi}) and k_{ro} is at interstitial water saturation (S_{wi}).

$$M = \frac{k_{rw}/\mu_w}{k_{ro}/\mu_o} = \frac{0.06/1.6}{0.27/14} = 1.97 \tag{1}$$

M = 1.97 indicates an unfavorable mobility ratio and implies fingering rather than piston-like displacement. This is consistent with the values for fractional flow of oil and water observed during imbibition. Rather than a gradual decrease in the fractional flow of oil, as would be expected, the observed values decreased to zero and then increased to greater than zero at a later time during the flood.

Thin sections were made at 1 foot intervals from 1492-1495 ft. to characterize the minerals, clays, depositional environment, and general structure of the Round Tank Queen sandstone. The thin sections were stained blue to show the porosity and yellow for potassium feldspar (figure 1.4). In the pictures, the bright, multicolored areas are anhydrite.

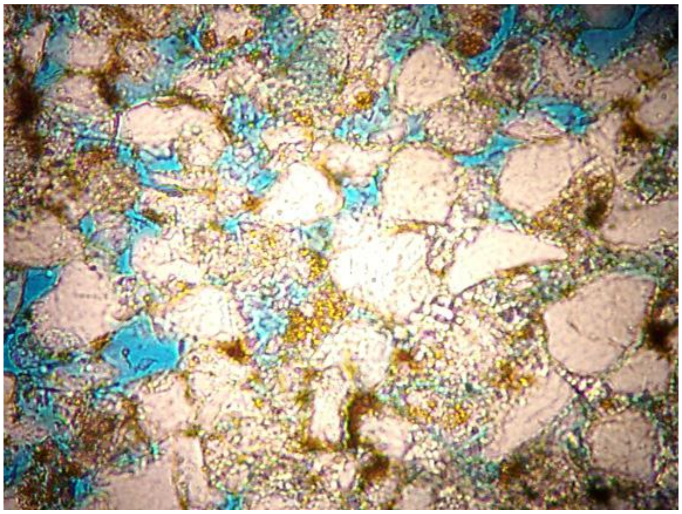

Figure 1.4 Thin Section at a Depth of 1492 Ft.

The field of view for this picture is 80 microns and the average grain size is estimated to be less than 10 microns. The amount of blue indicates fairly high porosity, with much of it being secondary from the dissolution of feldspars and cements. Some of the cements could have been gypsum, which would have been a precursor to the anhydrite cement. The sample is a fine grained sandstone

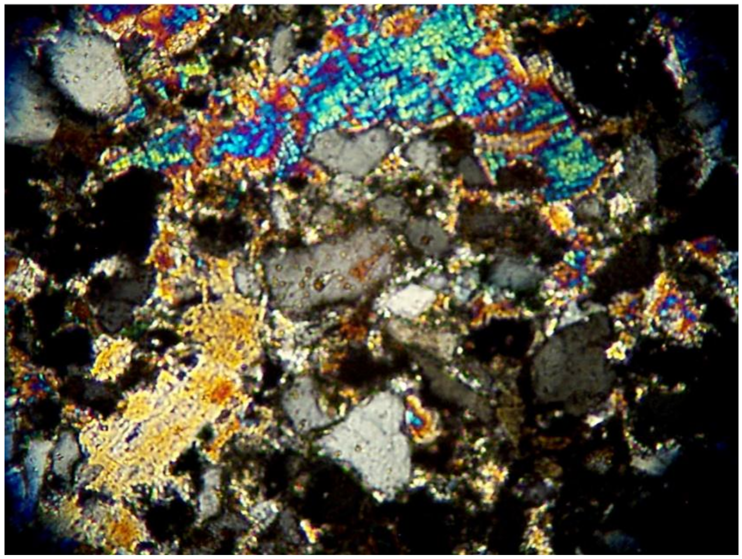

Figure 1.5 Poikilotopic Anyhydrite Cement at a Depth of 1492 Ft.

Poikilotopic means one large crystal that engulfs many small grains. Figure 1.5 shows a good example of poikilotopic anyhydrite as the anhydrite seems to surround all of the sand grains and provide a colorful backdrop. The chemical structure of anhydrite is $CaSO_4$. Gypsum is simply anhydrite with the addition of water or $CaSO_4$+H_2O. The cement was probably deposited as gypsum and then transformed to anhydrite from the high pressure at depth. While flooding, it is possible that the anhydrite transformed completely or partially into gypsum with the addition of brine into the cores. This would account for as much as a 38% increase in volume of the anhydrite and drastically reduce core permeability.

To further understand the mineralogy SEM photos were acquired for several samples. Figure 1.6 is a BSE image of the anhydrite that is typical of the anhydrite found above and below the Queen sand. The lower density anhydrite cement is lighter, while the higher density quartz grains are darker.

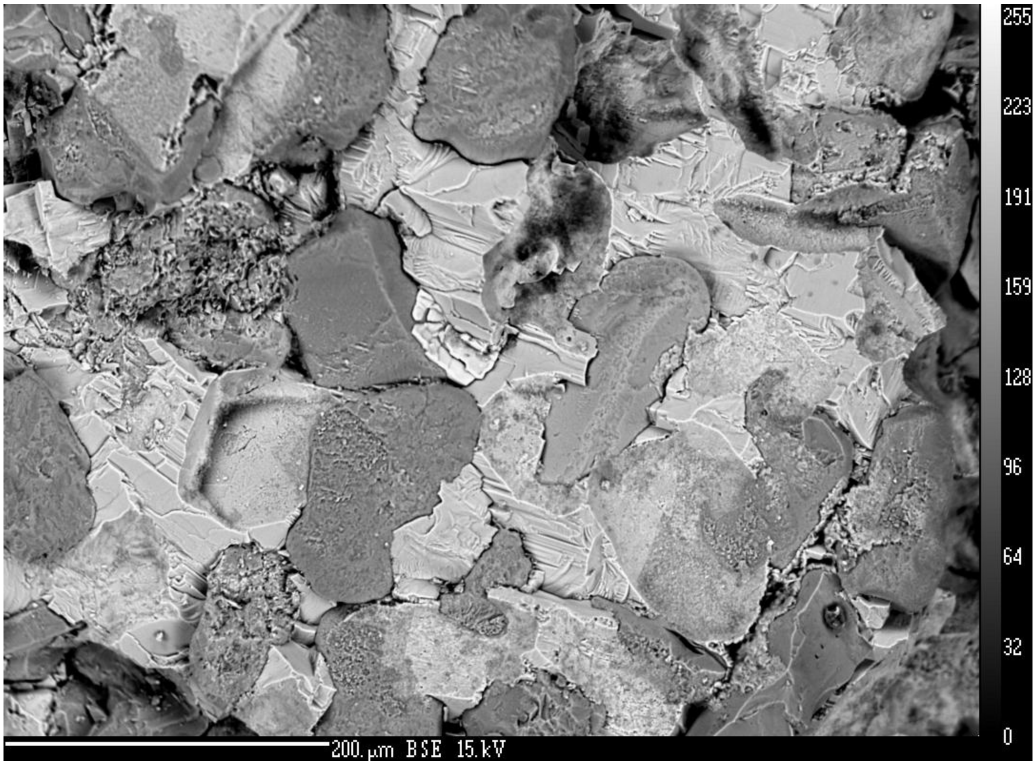

Figure1.6 BSE image of Anhydrite at 1502 Ft.

In the following images, an unflooded rock fragment (Fig. 1.7) is compared to a flooded rock fragment (Fig. 1.8) taken from core #2. The unflooded SEM images are of the rock that core #2 was cut from, which was never flooded. The rocks should be similar as they are both taken from the same depth of 1493.2 ft.

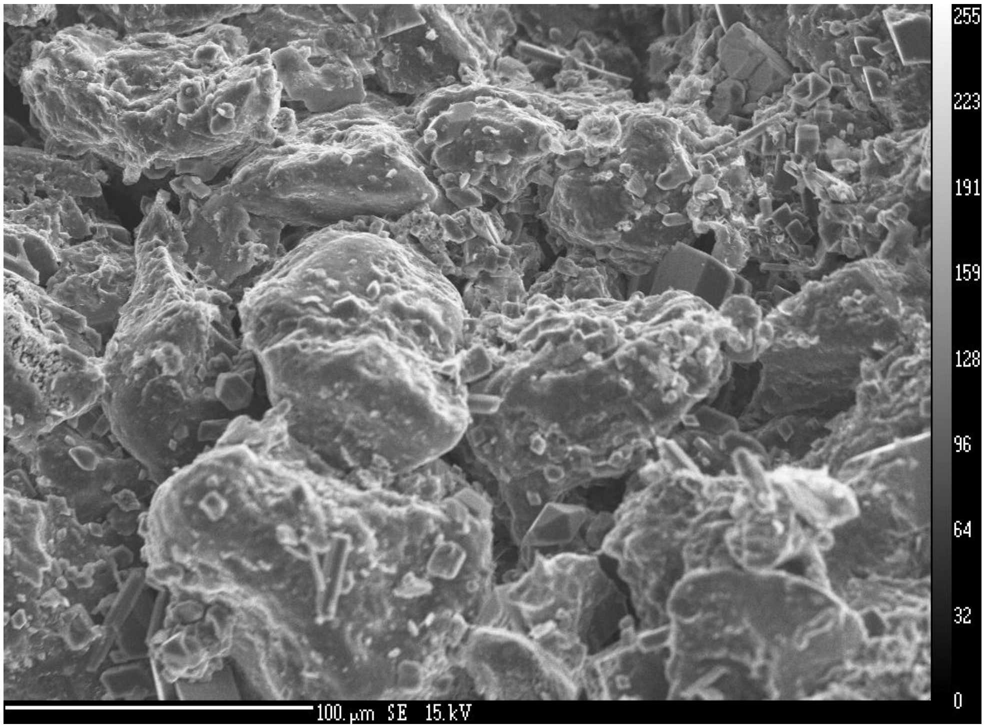

Figure 1.7 SE Image of Unflooded Rock, 100 Microns

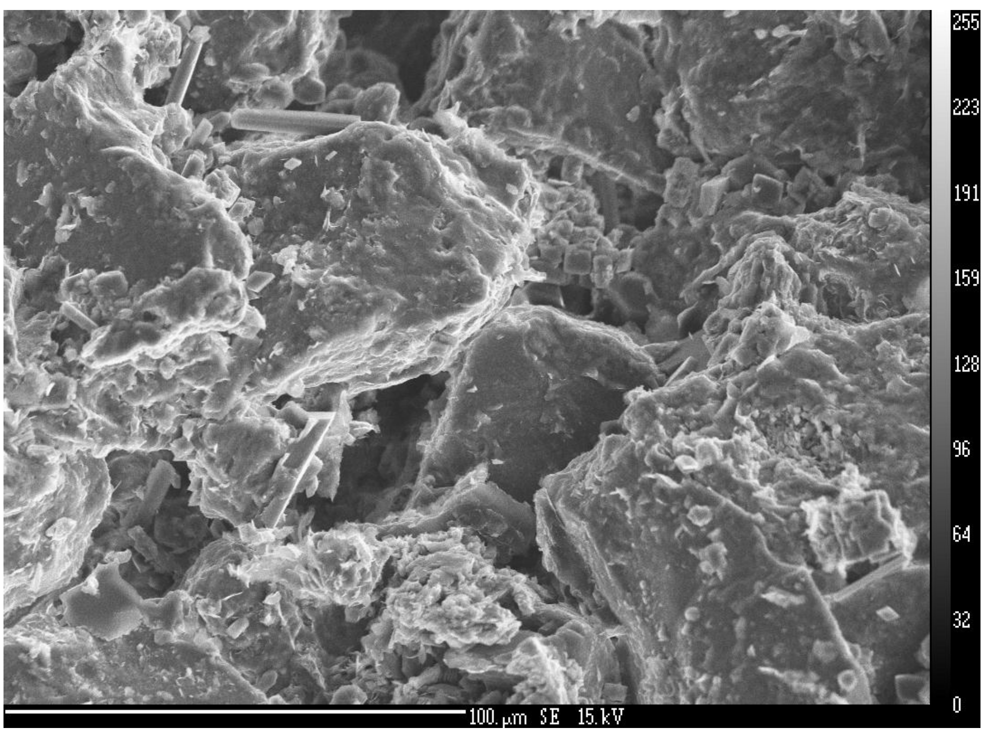

Figure 1.8. SE Image of Flooded Rock, 100 Microns

The differences between the two images are not immediately apparent, but upon closer inspection, one can see that the particles in the pore space seem to be less organized in the flooded picture than in the unflooded picture. These particles which appear as straight, stick - like figures are either dolomite or calcite. The rhombus shaped particles are of unknown composition, but could be mica. The clay is thought to be illite. ***The large amount of particles shown in the SEM photographs lends more credence to the theory that fines migration occurs in the Round Tank Queen sandstone.***

Figures 1.9 and 1.10 respectively show unflooded and flooded rock with 50 microns as a point of reference. In Figure 1.10 it is much more apparent that the rock has undergone flooding. The particles within the pore space of the flooded picture are clearly more disorganized and clay swelling, indicated by the string – like texture on the surface of the sand grains, is noticeable. Rather than sitting neatly on the surface of the sand grains, the rhombus and stick – like figures seem to be enveloped by the clay swelling. If the clay swelling does render the fines immobile, it might explain the odd pattern of changes in core permeability shown previously in the reverse flow permeability tests.

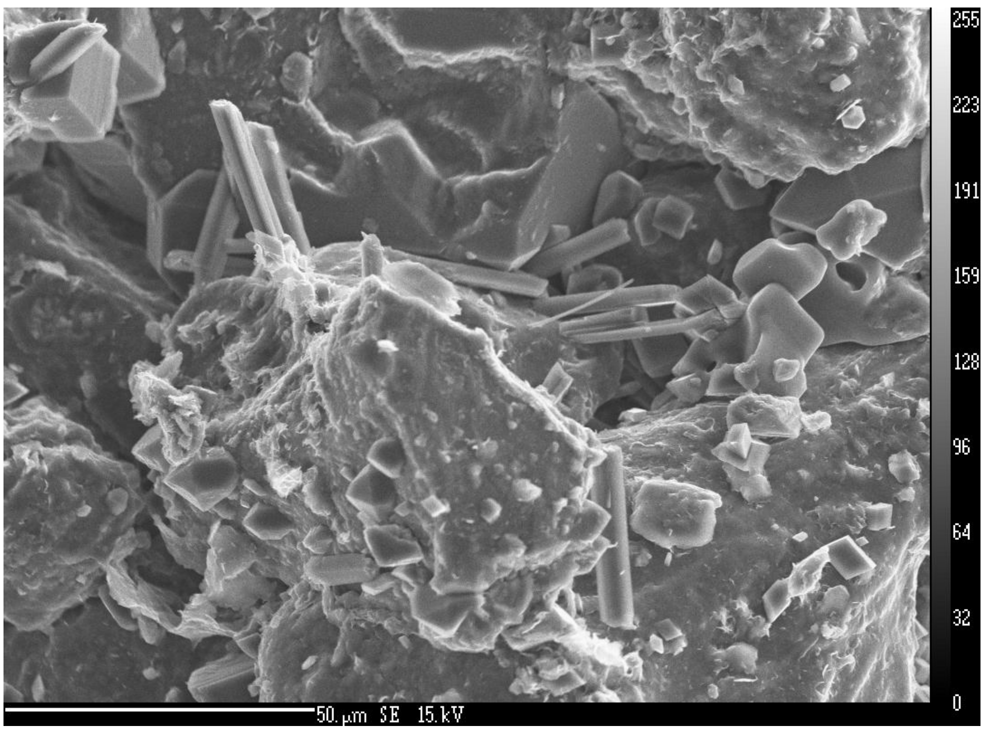

Figure 1.9 SE Image of Unflooded Rock, 50 Microns

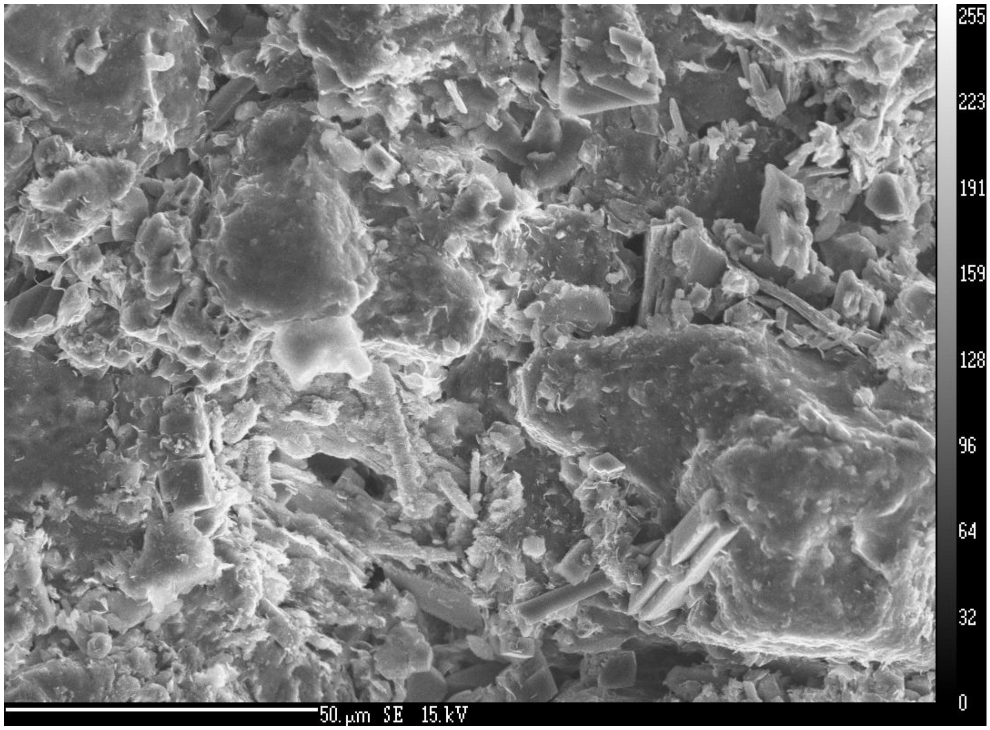

Figure 1.10 SE Image of Flooded Rock, 50 Microns

1.4 Conclusions

1. Despite the differences in the San Andres and Queen brines, the San Andres brine and the Queen rock seem to be compatible.
2. Evidence supports fines migration and clay swelling in the core. The result is rapid reduction in permeability during water flooding.
3. Anhydrite layering occurs to a lesser degree in the pay zone, but some anhydrite to gypsum transformation may still occur during water flooding of the pay zone. This will cause the anhydrite to swell which will reduce permeability.
4. When performing core analysis, measurement utensils with greater precision should be utilized.
5. Further work should be conducted on mitigating the effects of fines migration and clay swelling during water flooding.

2. Reservoir Characterization and modeling

2.1 objective

The objective of this segment of the project was to develop a reasonably accurate reservoir model for the purposes of simulating flow behavior in the pilot waterflood area and thus predict oil recovery. After successfully simulating the pilot, the next step was to simulate various waterflood development strategies for the entire field and identify the best option to the operator for consideration.

2.2 methodology

A common problem in small, mature fields is the limited and poor quality data, typically consisting of only old logs and production history. Thus evaluation of this field relies on existing data or data which are easy to acquire; high cost information such as seismic and special wireline logging are not available. Old logs (circa 1960s), 14 modern logs and one-core are the main sources for this reservoir study. Basically, the results from modern-log analysis will be used to calibrate and support the results obtained from the old logs. The main problems applying old logs are (1) the poor quality and reliability and (2) the required conversion of the neutron logs from API or CPS scale to porosity units. Normalization of old neutron logs and calibration of old sonic logs were two techniques applied to acquire valuable information. Details of the algorithms can be found in Srichumsin (2011) and Srichumsin and Engler (2011).

The petrophysical data was imported into Surfer™ software to generate structure and porosity contour maps. The full-field model was constructed; with dimensions of 4sections x 4sections x 3layers, 120x120x3 grid blocks. Figures 2.1 is an example illustrating the depth to the Top of the Queen.

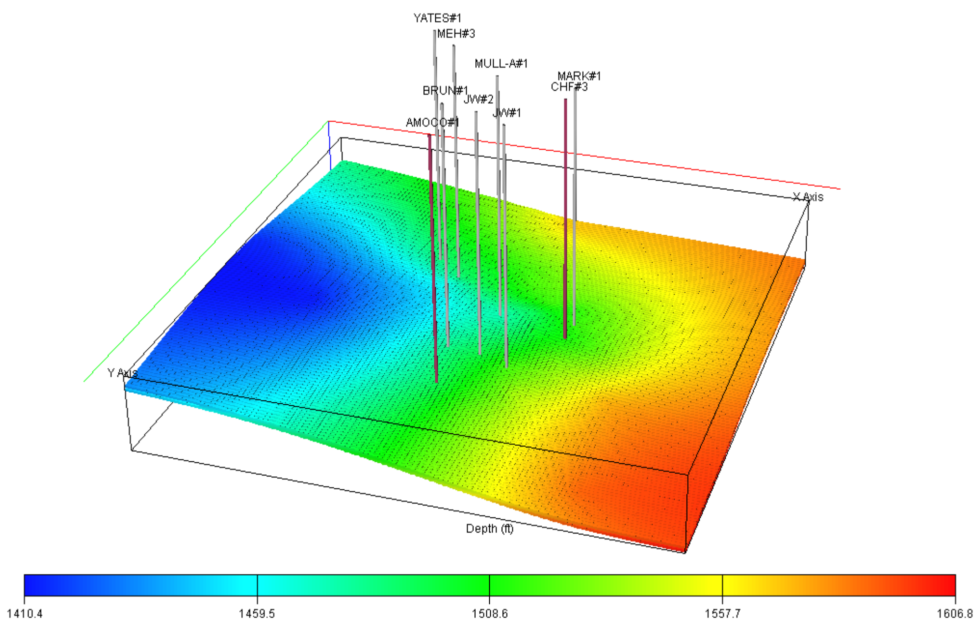

Figure 2.1 Depth (ft) for the top of the Queen sand in the Round Tank simulation model

To describe fluid flow in the Queen Sand reservoir requires accurate definition of the geologic flow units within the sand. A stratigraphic layering approach was chosen to identify the number of layers and layer thicknesses. The work was done by applying gamma ray logs as the main source for classifying layers. As a result, the Round Tank Queen sand can be divided into three layers (figure 2.2) based on gamma ray values. Layer3 contains the highest gamma ray response and porosity values. It is also the friable sand zone. Anhydrite layers exist on top and bottom of the Round Tank Queen sand and are easily identifiable. These layers are consistent throughout the area and provide excellent seals the Queen.

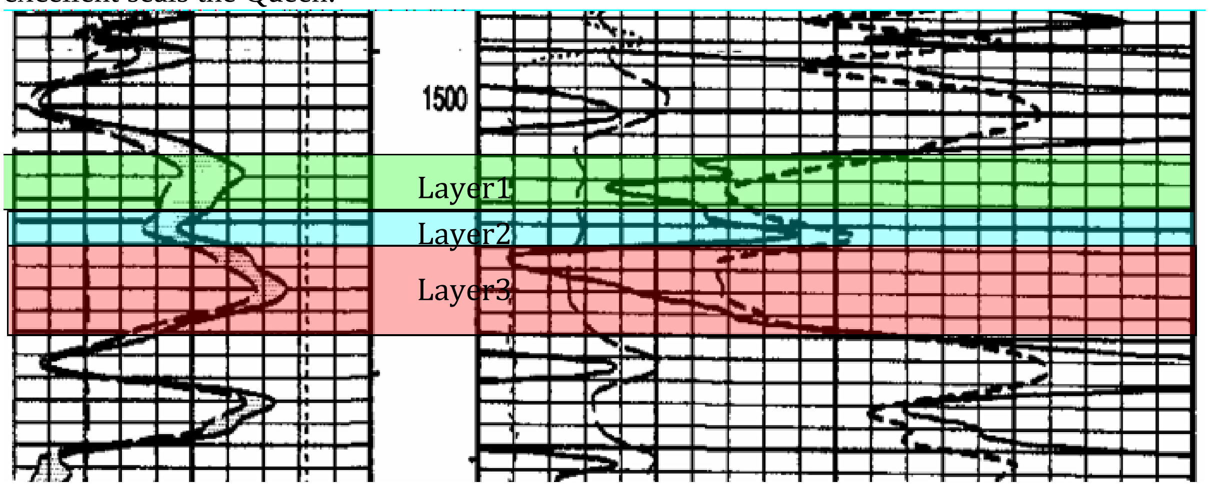

Fig.2.2: Gamma ray and density & neutron logs from Eskimo State #1 illustrating the three layers present.

Permeability within the consolidated area/layers was correlated to porosity based on core data from adjacent Queen pools (blue line in figure 2.3). In the friable sand the correlation was generated from the Round Tank Queen core experimental data (red line in figure 2.3).

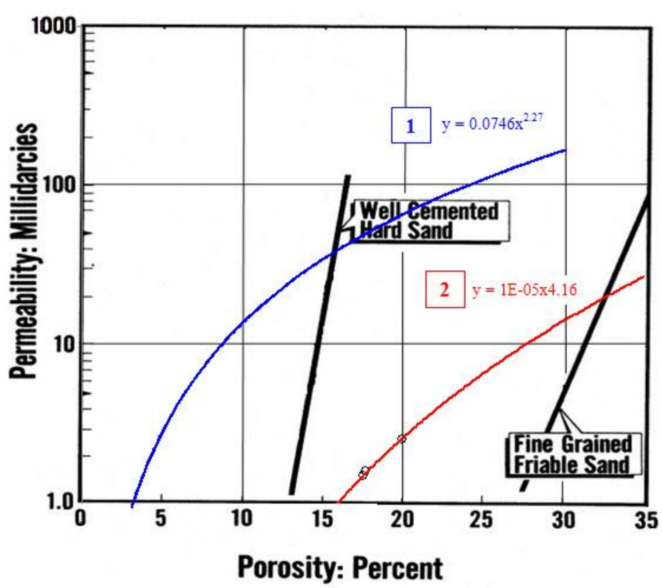

Figure 2.3: Porosity-permeability correlations for simulation model plotted along with published correlations

To validate the model, simulated reservoir pressure and well production are the two main parameters that need to match with the actual field records. History matching was accomplished using production rates as the constraining variable and pressures as the matching variables. Existing producing wells, both gas and oil, are in advanced stages of depletion and thus operate at very low bottom hole pressures.

2.3 Results and discussion

Mineral identification was also made through gamma ray spectrometry tool with the assistance of Schlumberger mineral identification chart (Figure 2.4). The chart, basically, is used to determine the type of radioactive minerals in a shaly formation from potassium and thorium concentrations measured by the gamma ray spectrometry tool. Details of thorium and potassium concentrations are available in three wells – Eskimo State No.1, No.2, and No.7. Figure 2.4 illustrates the results after overlaying data points onto the chart. Three observations can be made from the figure. First, although traces of mica was observed in the core (thin sections and SEM), it was not considered a primary mineral component. An alternative explanation is the existence of two radioactive minerals; feldspar and illite. The combined effect would be to plot in a region between the two minerals; i.e., mica. This alternative is consistent with observations in the thin sections and SEM photos, where both feldspar and illite were present. The second observation is that Layer3 contains the largest amount of clay minerals in the formation followed by Layer1 and Layer2, respectively. Third, thorium/potassium ratios (Th/K) are quite consistent among layers (~1.7 Th/K). This indicates that constituents of clay minerals are quite similar among layers.

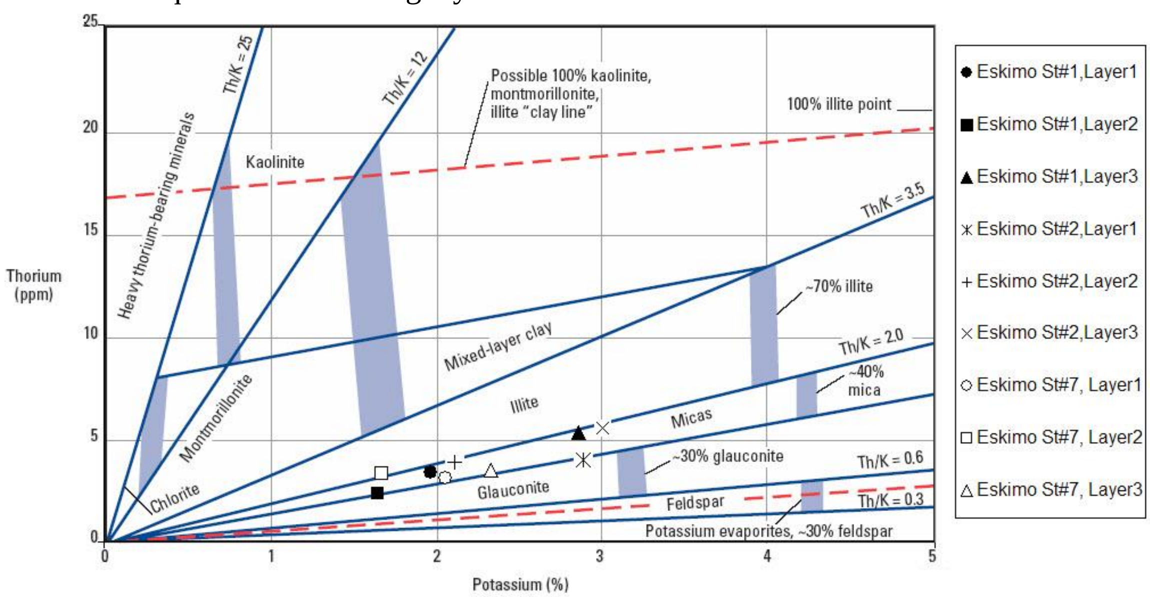

Figure 2.4: Schlumberger mineral identification chart plotted along with data from gamma ray spectrometry tool of Eskimo State No.1, No.2, and No.7

The pilot area model is shown in Figure 2.5 and the history match of the existing producer, Christine Federal No. 3 is shown in Figure 2.6.

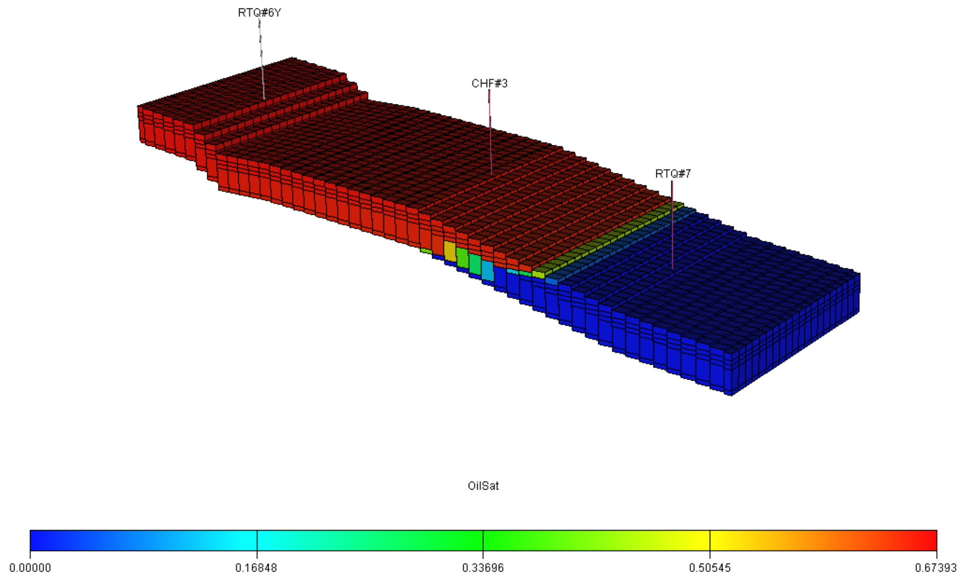

Figure 2.5 Pilot model area including five layers in the Queen sand. Colors denote initial oil saturation

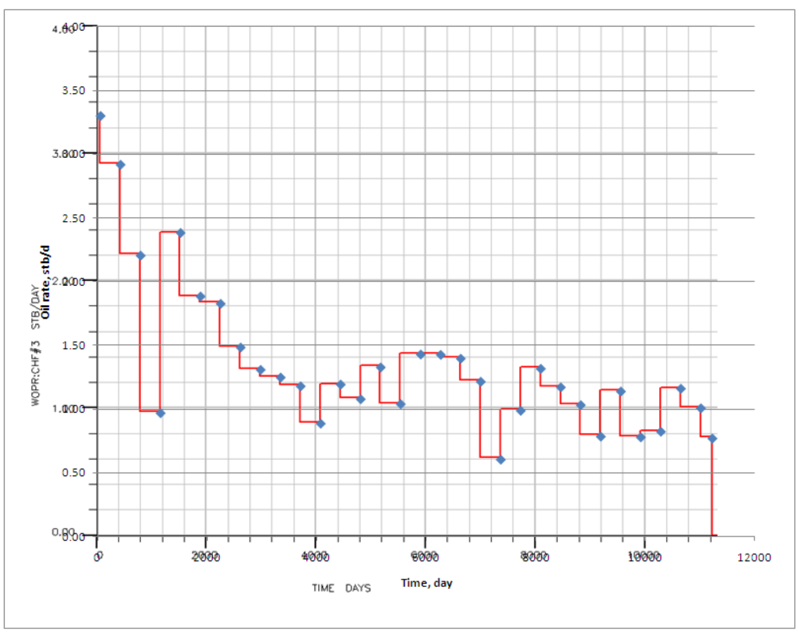

Figure 2.6 History matching of oil production rate for well Christine Federal #3

The reservoir pressure from the simulation (history matching phase) was depleted from 600psi to 41.5psi; in agreement with a recent recorded reservoir pressure of 50psi. The model provided an excellent representation of the production history of the pilot area.

For the prediction, bottom hole pressure of the injection well, RTQ#7, was assigned 600psi and oil production was from well RTQ#6Y. A 30 year forecast resulted in cumulative oil production after waterflooding of 167 mbbl; i.e., recovery factor increases from 1.3% to 16.5% of the OOIP.

For the pilot area the simulation model was used to study the effects of changing injector locations and changing of rock compressibility. An increase in rock compressibility doesn't affect the injection and production rate after waterflooding. However, the impact of rock compressibility on stimulation is significant, and will be discussed later.

Despite the failure of the pilot program, a flooding pattern (mini-waterflood) was proposed to locate injectors along the downdip edge of the oil column in the water leg, and producers along the updip edge of the oil column. The pattern design, well locations and spacing, strongly depends on the existing wells in the field to reduce the cost of infill drilling. New wells (Eskimo State No.1 to No.10) which currently produce from the deeper San Andres reservoir will be potential candidates for future injector and/or producer to the project. Figure 2.7 demonstrates the flooding pattern that will be used to predict the mini-waterflood potential of the field. The pattern consists of 6 producers and 6 injectors. Five additional wells, NMT No.1 to No.5, need to be drilled to achieve the flooding pattern with 40 acres spacing.

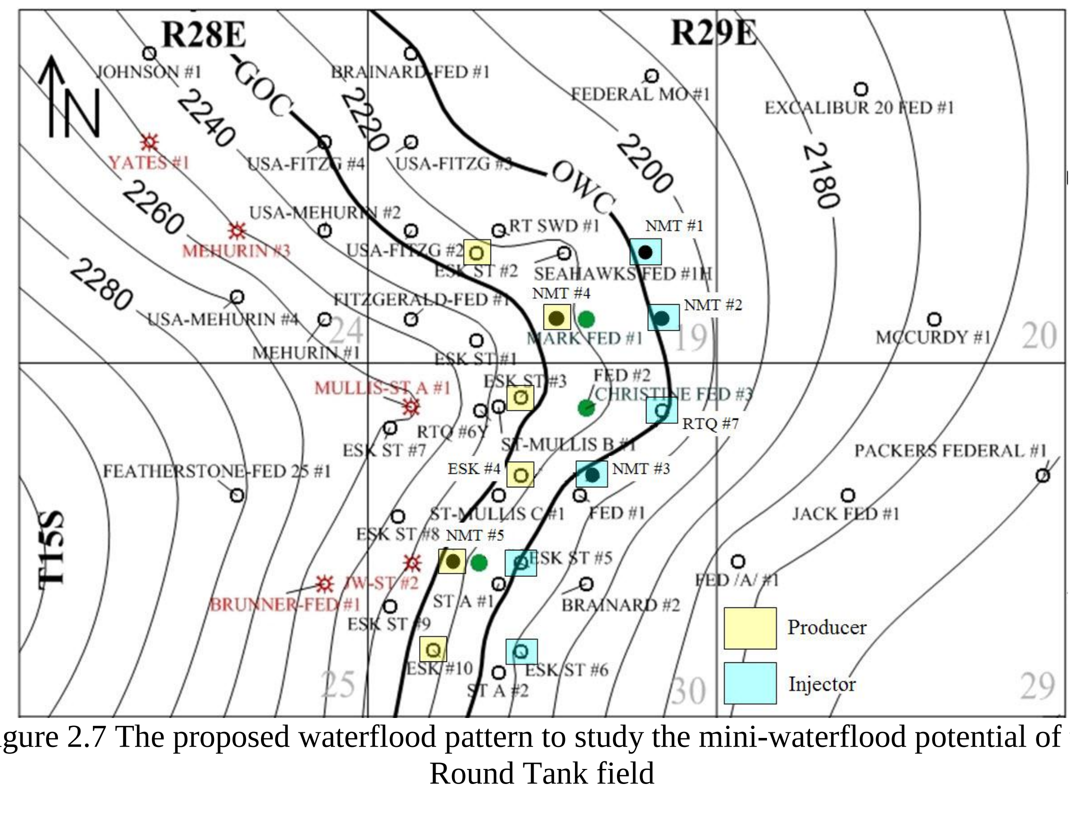

Figure 2.7 The proposed waterflood pattern to study the mini-waterflood potential of the Round Tank field

History matching results from the original model shows that reservoir pressure simulated from the program is much higher than the actual data, as well as the bottom hole flowing pressures. (see Figure 2.8)

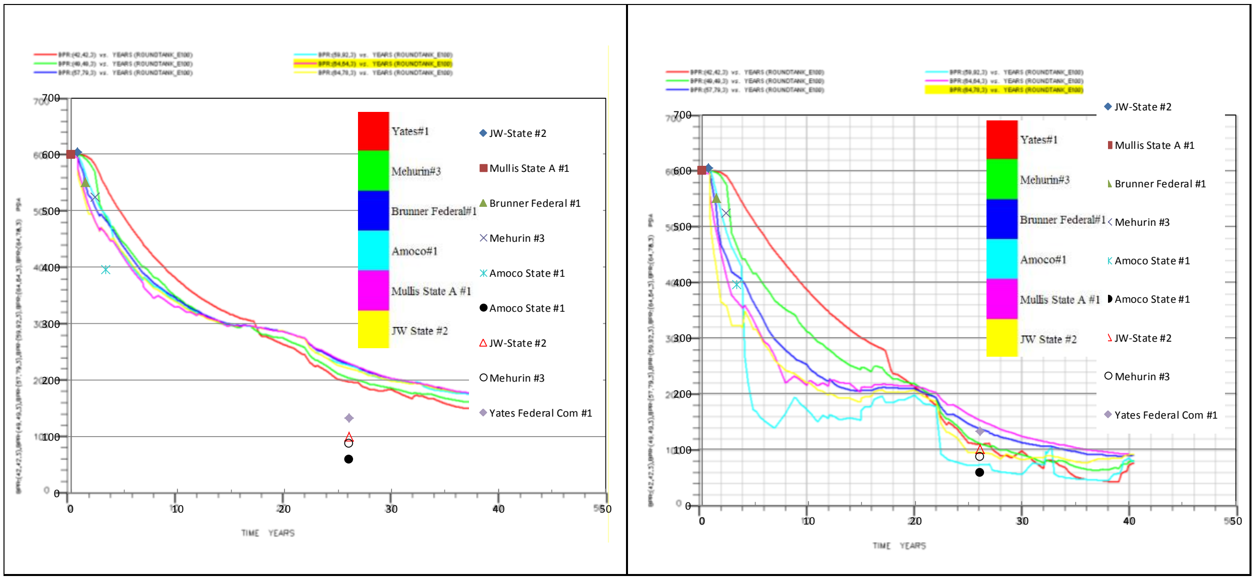

Figure 2.8. Actual field pressure measurements (symbols) overlaying the simulation results (lines). Left diagram is the original model. Right diagram is the final model after the below modifications.

Therefore, the following major adjustments were made:

- Increase porosity and reservoir boundary in the northernmost part
- Reduce porosity and reservoir boundary in the southernmost part
- Modify regional porosity and permeability in some area
- Reduce Layer1's permeability by 60%
- Reduce permeability of Layer2 in the consolidated area by 60%
- Reduce permeability of Layer3 in the consolidated area by 75%
- Increase k_{ro} by 30%
- Increase Cp from 20E-6 psi^{-1} to 40E-6 psi^{-1} (adjusted to match recent reservoir pressure in water zone). The recent reservoir pressure was obtained from the new well, Round Tank Queen Unit No.7.

The final, successful history match was obtained and is shown on the right side diagram of figure 2.8.

The prediction was performed by running the simulation for 20 years, starting from Jan 2011 to Jan 2031. Injection and production rates were controlled by bottomhole flowing pressures. All production wells produce with the minimum bottomhole flowing pressure while fracture pressure of the Round Tank Queen formation (~900 psi) was used as the maximum bottomhole pressure for limiting water injection. The prediction results (Figure 2.9) show extremely poor water injection and oil production. On average, only 3.5 BWPD/well could be injected, and 1.33 BOPD/well could be recovered. Further, the observation of oil saturation and reservoir pressure through time (Figure 2.10) also indicates the poor waterflooding performance - slow flood front movement and inability to increase reservoir pressure.

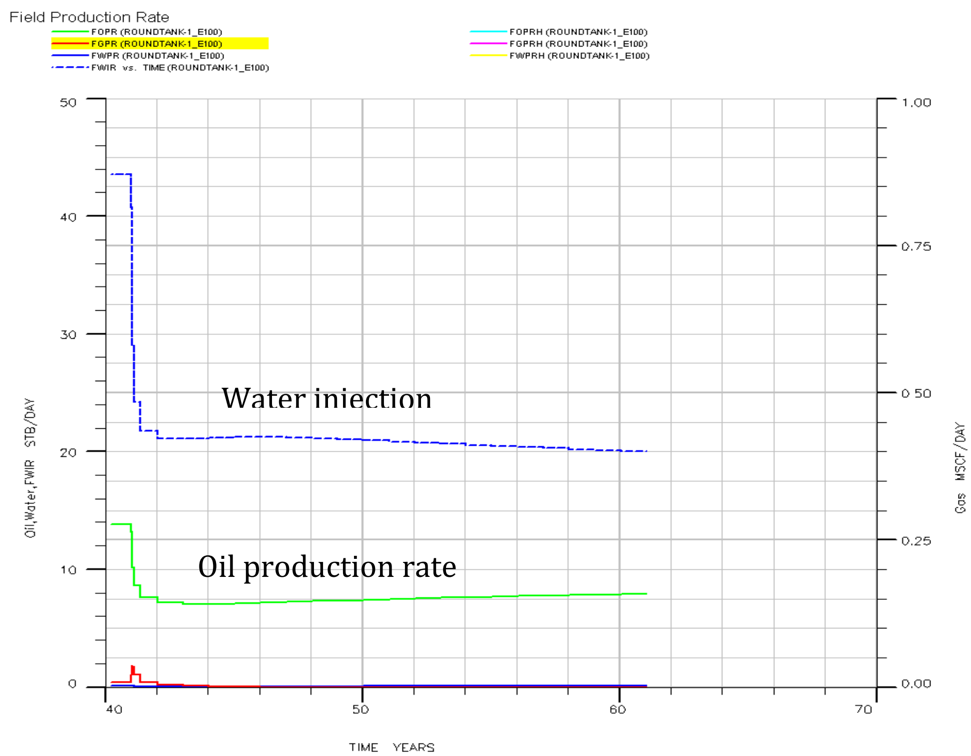

Figure 2.9 Field production and injection rates from 20 years prediction

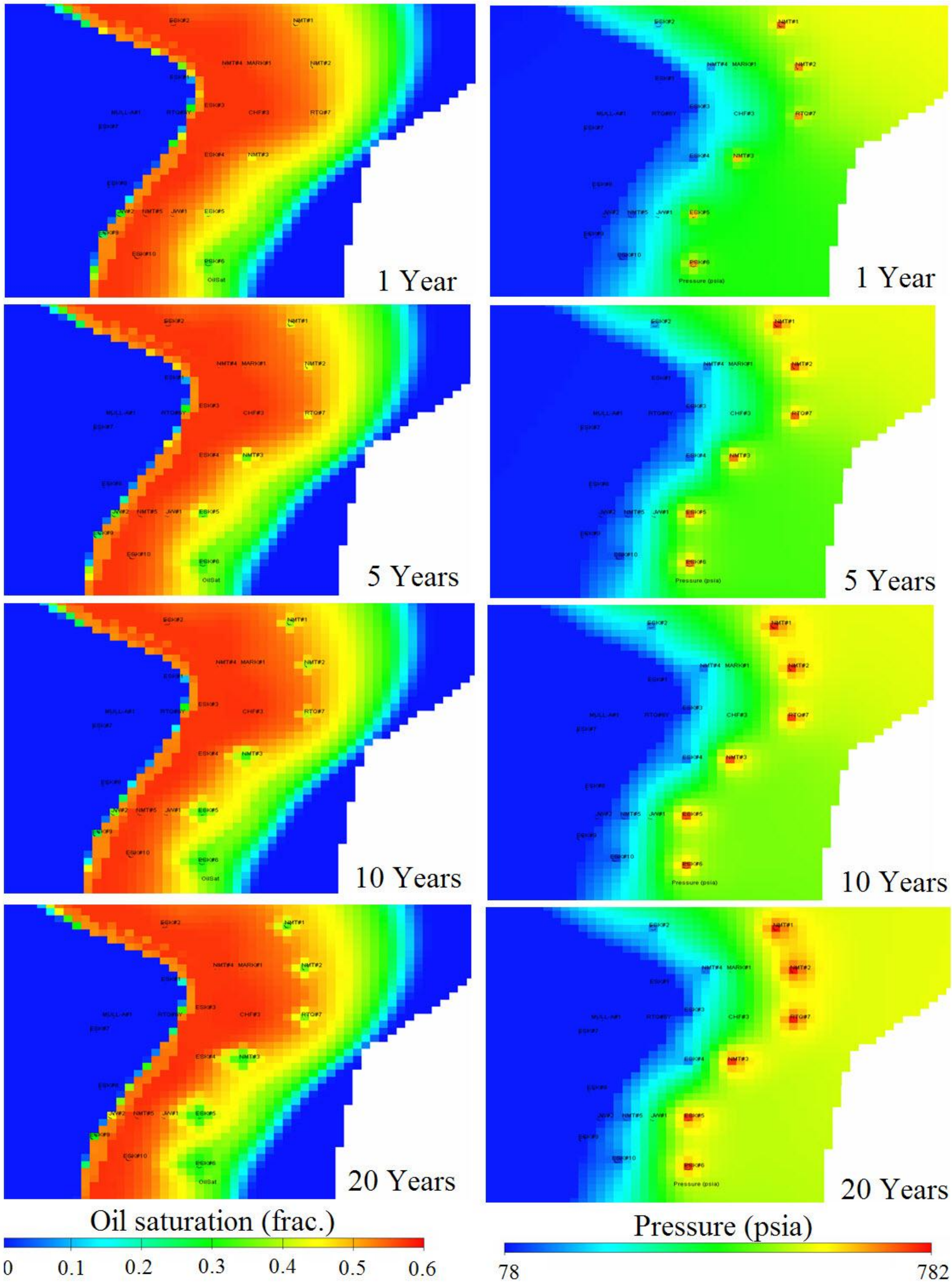

Figure 2.10 Oil saturation and reservoir pressure through time

The poor displacement performance is in response to the unfavorable mobility ratio: M > 2; specifically, the high oil viscosity, and relative permeability ratio. Simulation runs were made for reduced oil viscosities of from 13.67 cp to 7 cp and 3 cp accordingly. The results show approximately a doubling in oil production rate with each decrease in oil viscosity.

The influence of the depleted reservoir pressure to waterflooding performance was also investigated. The observation of pressure fill-up trend was made by running the simulation without opening any producers. The results show small pressure increase in oil and water zones; approximately 150 psi of pressure is increased for 20 years of water injection. The investigation was further made by multiplying permeability of the model with a factor of 10 to reduce the effect of poor transmissibility. The prediction results reveal that even at higher injection rate and better formation transmissibility, pressure fill-up is still unfavorable. The main reason could be due to the loss of pressure to the depleted gas-cap region and migration of oil into the gas cap region. Once oil moves into a gas-cap region, it will remain trapped and unable to recover (Willhite 1986). Thus, without any pressure maintenance in the gas cap, the proposed flooding pattern seems not to be effective even though the formation has high permeability.

2.4 Conclusions

1. Successful characterization of the Round Tank Queen reservoir with limited and poor quality data was made with the assistance of modern logs and core analysis.

2. Normalization of old neutron logs and calibration of old sonic logs were two techniques applied to acquire valuable information.

3. The study of mineralogy indicates that quartz is the main mineral of the formation with other minor minerals present a combination of potassium feldspar, anhydrite, micas and illite.

4. A newly discovered friable sand bed was identified and has implications on reservoir performance.

5. The results from history matching show satisfactory outcomes; a minor adjustment was made for the porosity distribution, and reservoir boundary was identified.

6. The large permeability reduction from history matching indicates that permeability of the Round Tank Queen formation is significantly lower than the other Queen sands.

7. The prediction results of the proposed flooding pattern show poor performance: low oil production and water injection rates, slow flood front movement and unable to fill-up reservoir pressure.

8. Many factors contribute to the poor performance including low permeability, high oil viscosity, depleted gas-cap and low differential pressure between bottomhole and reservoir.

3. Stimulation Evaluation

3.1 Objective

The variable mechanical properties of the Queen seen in the core and logs, and the presence of clays and fines migration, have implications on both hydraulic fracturing and water injection. For this reason, an investigation into the stimulation effectiveness of the injection well (RTQU #7) was initiated. Results will also assist the reservoir characterization and modeling efforts for this reservoir.

3.2 Methodology

After stimulation of the RTQU #7, there was no improvement as the water failed to flow through the formation. Potential explanations are:

- Fractured another interval within the well (theory supported by data from tracer logs)
- The fracture geometry was probably horizontal (theory supported by shallow depth of pay zone)
- The fracture closed due to the low rock compressibility of the friable zone

A fracture simulation study was conducted to address the reasons for possible failure. For this study, surface treating pressure data from the fracture treatment was history-matched with a pseudo 3D fracture simulator. Two fracture designs were compared: a vertical fracture with high proppant concentration in a restricted interval, and a horizontal fracture due to the shallow depth and high frac gradient. After a successful pressure match, results from the models such as height and fluid distributions were compared with results from the radioactive tracer and temperature logs, and to distinguish which design better agrees with the field data.

The fracture model was constructed across the height of the pay zone and included the anhydrite seals above and below the pay zone. Model properties were inputted for 24 layers across intervals of 1 ft. The lower portion of the queen had significantly lower stresses and higher values of porosity, permeability and leak-off to reflect the friable nature of the sand bed.

The well was stimulated by hydraulic fracturing through the casing at perforation depths of 1582 – 1598 ft. The perforations had 20 holes with 0.42 inches in diameter. The casing depth was 1694 ft with OD of 5.5 inches and ID of 4.95 inches. The fracture fluid used was Delta Frac 140 – R(15), the pad and flush fluid was Water Frac G – R(15) and the proppant used in this treatment is brady sand 12/20. The treatment was executed in six stages with increasing proppant concentration of 1 to 6 ppg per stage.

Propagation of a vertical or horizontal fracture is highly dependent on the existing stress conditions both in the Queen Sand and the upper and lower bounding layers. Actual stress measurements are not available; therefore the initial approach is to use published values for the various rock types. The generated stress profile will need to be consistent with the net fracture pressure plot and the tracer test.

Certain options were selected in the simulator to construct the model. The main options/assumptions necessary to simulate and simplify the model were:

- A harmonic fluid loss model which computes the total leak-off coefficient as a function of differential pressure
- A 3D geometry for both vertical and horizontal cases
- The minimum stress interval was selected as the fracture initiation point, this agrees with the theory that the fracture is initiated at the weakest point within the formation.
- A conventional (Link Proppant) model links the proppant transport to the fracture propagation solutions, thereby simulating the effects of slurry transport on fracture pressure distribution and propagation.

3.3 Results and Discussion

The vertical fracture design was pressure matched with the fracture simulator. The stresses, and the fluid leak-off, were the main parameters that were adjusted to obtain a pressure match. The stress gradients for the vertical model were adjusted from 0.61 psi/ft to values between 0.7 and 0.8 psi/ft to obtain a pressure match. The model predicted pressures were within 6% (more or less) of the observed data for most portions of the treatment. It had an average height of 179 ft and a fracture efficiency of 44%.

Similarly, a treating pressure match (figure 3.1) was obtained for the horizontal model. To obtain a pressure match for the horizontal model the insitu-subsurface stresses for the layers had to be increased above that of the vertical model (0.8 psi/ft) to a value close to the overburden (1 psi/ft). Also the ellipsoidal aspect ratio (ratio between the length of the major and minor ellipse axes) was increased to 8 to achieve a good pressure match. The significance of this ratio is that if it is one, then the fracture would be a standard radial or penny shaped geometry (Meyer user's guide). It had an average height of 0.03 ft and a fracture efficiency of 25%.

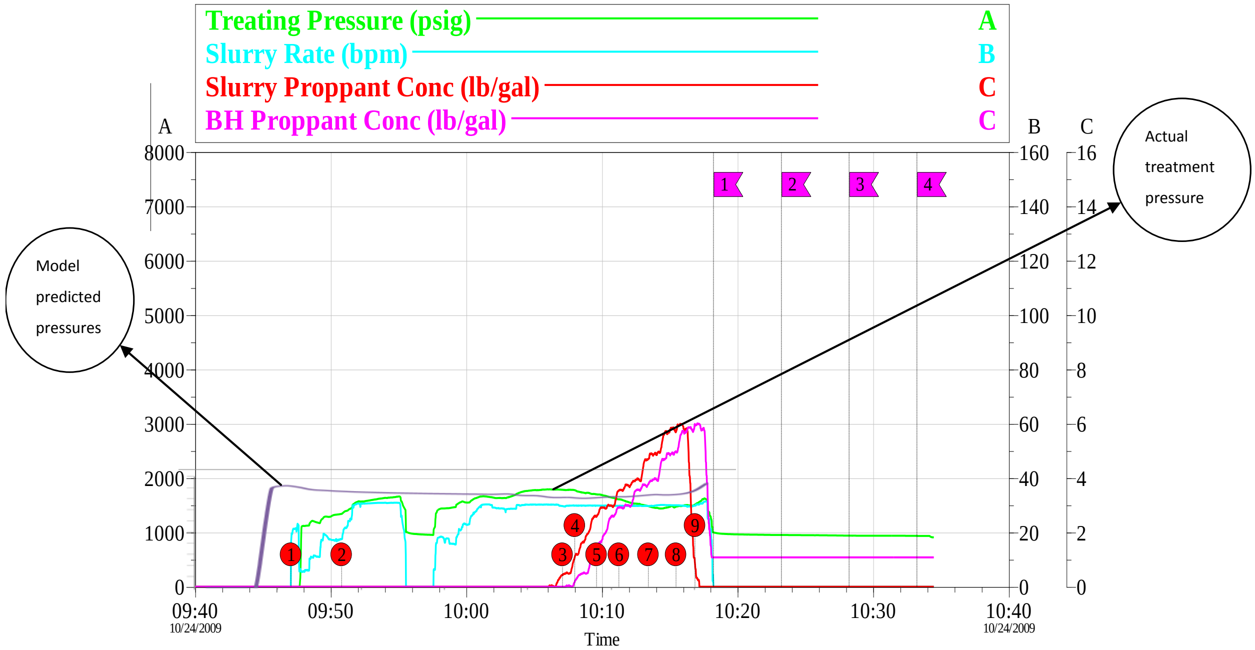

Figure 3.1: Comparison of actual treating pressure and model predicted pressure for the horizontal fracture model.

INTERPRETATION OF TRACER SURVEY

A tracer log was acquired to give insight to the fracture height and to understand the fluid and proppant distributions within the fracture. The log presented below, shows the radioactive tracer on the left and the accompanying temperature and velocity surveys on the right.

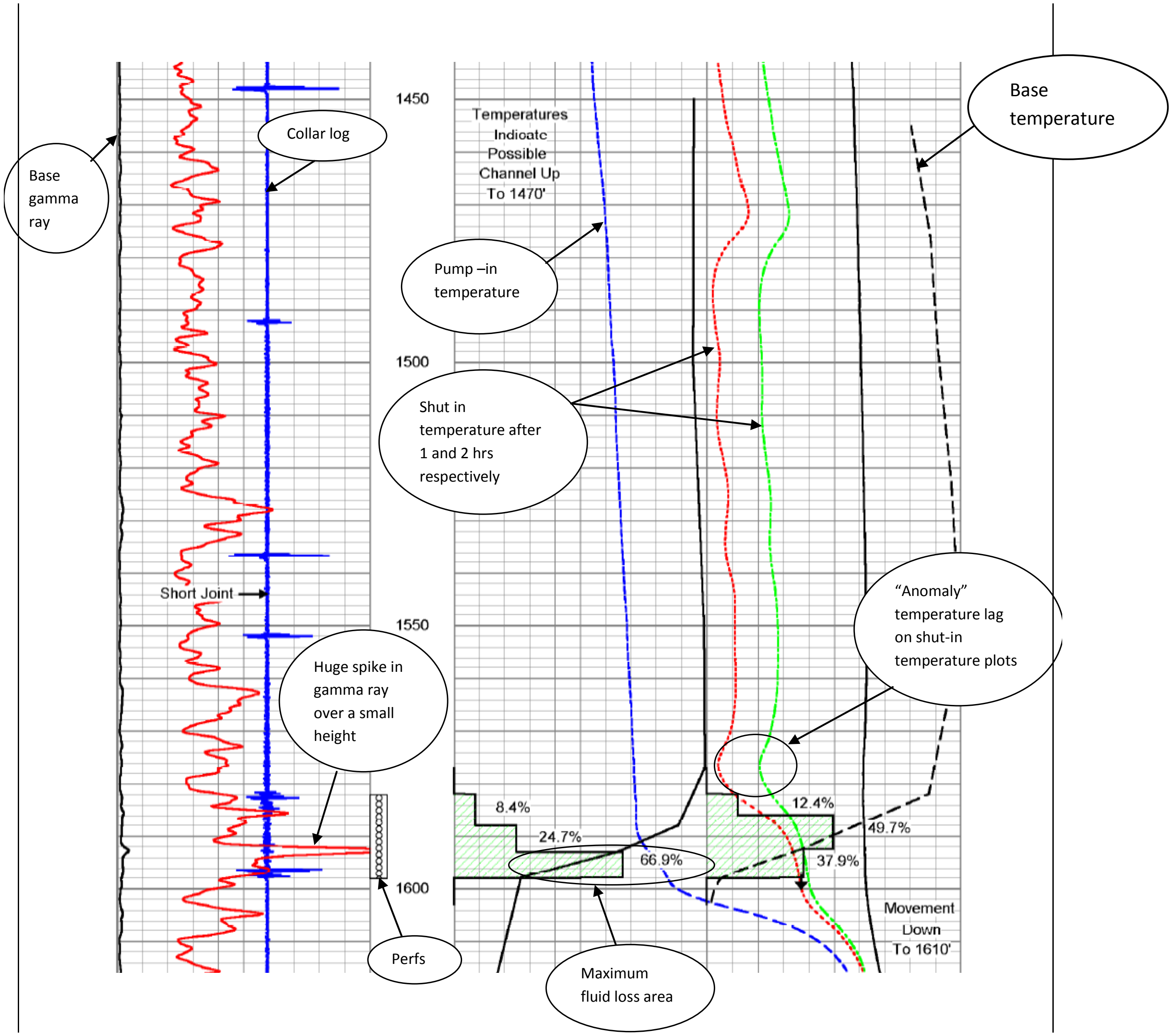

Fig. 3.2 Radioactive tracer showing the gamma ray, the temperature and velocity surveys.

Examining the tracer log (fig 3.2), one can observe that on the far left, the base gamma ray (pre-frac) is shown in black, while the gamma ray (post-frac) is shown in red and the accompanying collar log (blue) is shown to indicate the pipe joints. The temperature log is shown in four plots – the normal geothermal temperature plot (black, short dashes), the temperature plot at the time of pumping (blue) and the shut-in temperature plots after 1 and 2 hours (red and green).

A spike (increase) in the gamma ray reading occurs within an interval of two feet at a depth of 1592-94 ft. This spike suggests that most of the radioactive proppant entered this interval and thus represents an extremely small fracture height; supporting the concept of a horizontal fracture. If the fracture were to be vertical, then radioactive proppant would be dispersed among the entire perforated interval.

Temperature logs provide a qualitative assessment of fracture height. Consequently, the height predicted by the temperature survey (8ft) is more than that of the radioactive tracer (2ft). This is due to the fact that the radioactive survey only gives the "propped" height of the fracture while the temperature survey tends to indicate the fluid (created) height.

Examining the velocity loss profile in fig 3.2 above, notice minimal fluid loss (8.4%) at the top of the target zone, some fluid loss (24.7%) at the middle of the target zone but the majority of the fluid loss (66.9%) occurs at the base of the target interval. The high fluid loss zone coincides with the radioactive spike observed on the gamma ray log.

FRACTURING PRESSURE ANALYSIS

Fracture diagnostics is a powerful tool to determine behavior of fracture propagation and provide parameters for the design of future treatments. One such tool is the Nolte-Smith net fracture pressure plot shown in Figure 3.3.

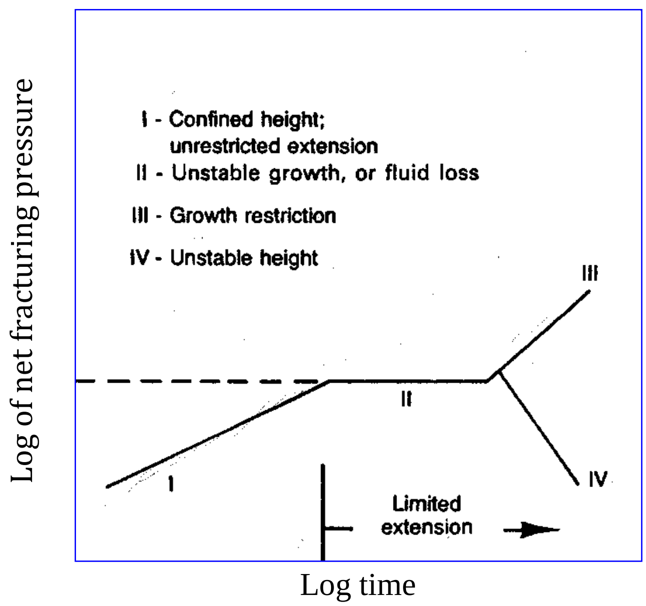

Figure 3.3 Schematic of net fracture pressure indicating progress of fracture extension

The different modes of propagation are:

Type I: Increasing net pressure as the fracture propagates in the formation Confined height

Type II: Constant pressure plateau can result from unstable growth or fluid loss

Type III: Fracture growth ceases…continued injection increases width of fracture and pressure, i.e, balloon effect.

Type IV: During fracturing, if a barrier is crossed and encounters a lower stress zone, then $p_f > \sigma_{zone}$ and accelerated growth will occur.

For a horizontal (T-shaped) fracture the expected fracture pressure behavior is shown in figure 3.4.

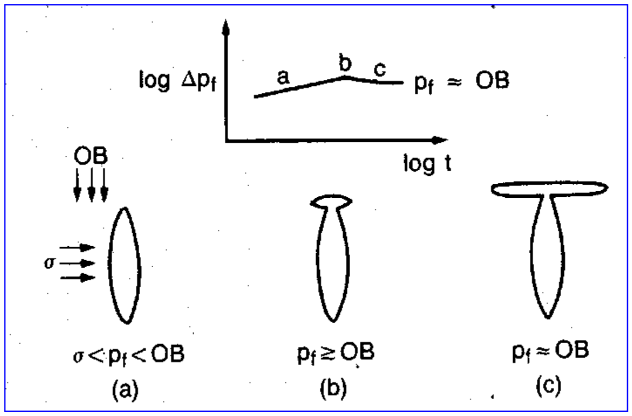

Figure 3.4. Type II: Pressure and width for T-shape fracture

The net pressure plot for the subject well is shown in Figure 3.5. Notice the approximately constant (zero slope), neglecting the slight changes (in the slope) as stochastic variations within the formation. This means the treatment was dominated by large increases in fluid loss and unstable growth (Nolte and Smith, 1981). This is a reasonable interpretation, because the reservoir rock had high permeability, high porosity and was loosely consolidated. The high fluid loss can also be attributed to the highly porous friable sand zone within the formation. The constant plateau pressure behavior is indicative of creating a horizontal fracture.

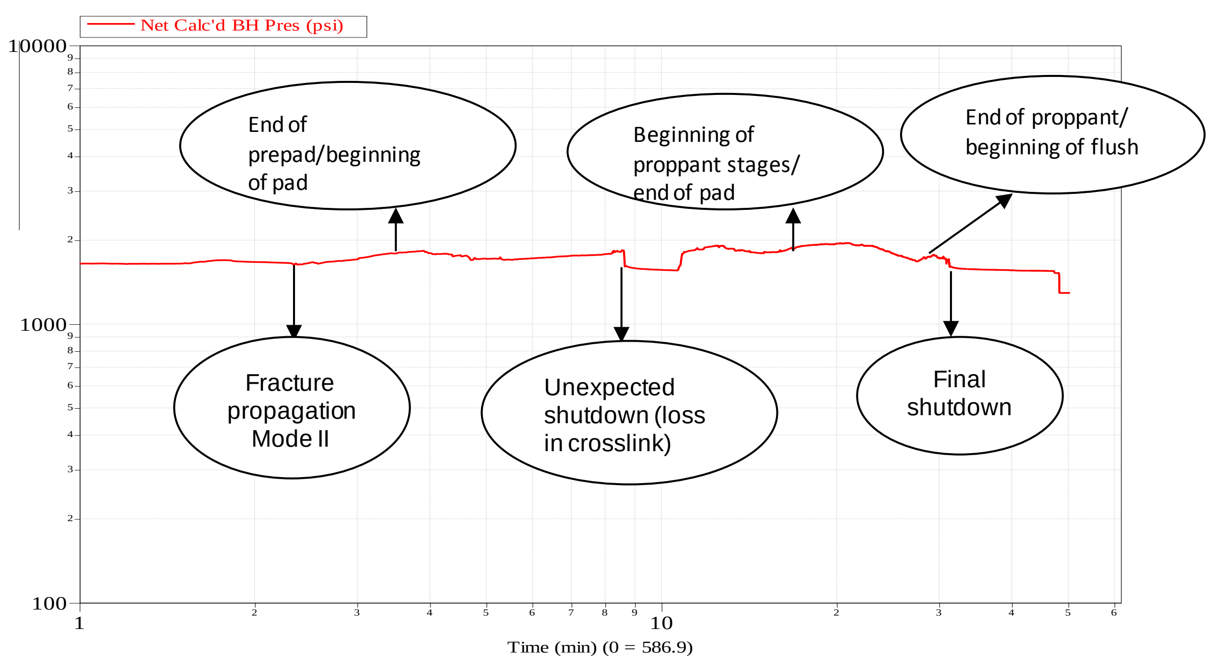

Figure 3.5 Net pressure plot (Log Pressure vs Log Time) for the RTQU No. 7.

COMPARISON OF VERTICAL AND HORIZONTAL MODELS WITH TRACER SURVEY

As was indicated earlier on, the radioactive tracer is more reliable than the temperature survey because it has fewer limitations, therefore only the gamma ray results were compared with the vertical and horizontal models.

The fracture height from the radioactive tracer is about 1 ft, while the height from the vertical model results was excessive at 179 ft and that of the horizontal model was about 0.03 ft. From these results, it can be concluded that the fracture is horizontal in an area within 4 to 5 ft away from the well bore. Therefore the horizontal model is adopted as the fracture geometry. Also from the radioactive tracer, the horizontal fracture is located at a depth of 1592 ft. This depth is the lower part of the pay zone, which has the highly porous, highly permeable friable sand bed. Thus the horizontal fracture is believed to be located within this friable sand zone.

Generally, horizontal fractures in a vertical well (pan cake fractures) are not as efficient as vertical fractures on a vertical well. In this study, the horizontal fracture efficiency was 25%, while the vertical fracture efficiency was about 44%. Since the injectivity of the reservoir was not improved (operator reported several problems such as sharp pressure increase during waterflooding) after the well was fractured, it is safe to say that the fracture treatment was not successful.

3.4 Conclusions

As an example, fracture toughness measures the ease with which the rock gets broken or fractured. The more brittle the rock the lower the fracture toughness as it cannot withstand the pressure force, while the more ductile rock types have higher fracture toughness as they tend to compress rather than break, when pressure or force is applied. Fracture toughness is a measure of a materials resistance to fracture propagation. It is proportional to the amount of energy that can be absorbed by the material before propagation occurs.

The relevance to the Queen sand is the existence of the friable sand zone in layer three. The friable nature makes this sand more ductile; i.e, compressible, and thus negatively impacts the hydraulic fracture propagation.

Numerous parameters are required to properly apply a stimulation propagation model; many of which are unknown and therefore contribute to the uncertainty of the results from the stimulation model. Of particular interest are parameters which would vary between the horizontal and vertical fracture models. That is, what would be the variation in a given parameter to obtain a match with the measured treating pressure? And which of these parameter values is realistic.

The most significant parameter to impact the models has been the insitu stresses. A common (assumed) insitu stress gradient is 0.5 to 0.6 psi/ft. Using this value underpredicted the measured treating pressures. For the vertical fracture model, to obtain the best match to the measured pressure data required an increase in the insitu stress gradient to 0.8 psi/ft. To obtain a pressure match for the horizontal fracture model the insitu-subsurface stresses for the layers had to be increased above that of the vertical fracture model to 1.0 to 1.1 psi/ft. The observed fracture gradient was 1.06 psi/ft and thus is comparable to the horizontal fracture model results. This supports the hypothesis of development of a horizontal fracture in the Queen sand.

Analysis of the stimulation in the injection well supports the creation of a horizontal hydraulic fracture in the Queen formation. Evidence to support this conclusion is:

- Analysis of the tracer survey confirmed a fracture height of only one foot within this 16 foot sand.
- Analysis of Nolte-Smith net pressure plot exhibited a constant pressure plateau indicating that the fracture treatment was dominated by regions of high fluid loss (due to high permeability, loose consolidation) and unstable growth; both present in horizontal fractures.
- Using a pseudo-3D fracture simulator, a comparison was made between a vertical and a horizontal hydraulic fracture model. The horizontal model provided a better match to field data; specifically the model fracture gradient of 1 to 1.1 psi/ft agreed with the measured fracture gradient of 1.06 psi/ft.

The treatment failed mostly because the created fracture was horizontal intersecting a vertical well (Pan Cake fractures), with a very small width and propped width. In addition, the compressible friable sand layer acted like a sponge; i.e., compressing when adding pressure (or force) but not cracking to create length needed for fracturing. As a result the energy of the fracture treatment was diverted to the lower quality Queen layers or dissipated after the treatment.

4. Impact to Small Producers

Even though we were unsuccessful in efforts in the Round Tank Queen Field to improve oil recovery and extend the life of the reservoir, several benefits as a result of this work are provided to others with similar situations. First, improved reservoir description was accomplished with limited data: old Neutron and sonic logs, fourteen modern logs, and one core and thus did not require high cost information. Second, the importance of stimulation design cannot be over-emphasized. In this case, the occurrence of a friable zone in a shallow reservoir increased the complexity of the stimulation. The result was a horizontal hydraulic fracture of limited conductivity. This information is considered valuable to the development of analogous Queen fields in Southeast, New Mexico, all of which are operated by small producers.

Figure 4.1 illustrates the target. Cumulative oil production is shown for over thirty Queen fields in Southeast New Mexico, along with whether or not the field was waterflooded. The very low oil production in the Round Tank ranks the field as one of the least productive Queen Oil fields in the area. It can be seen from the figure that the higher the cumulative oil production, the greater the likelihood of a field being waterflooded and vice versa. This confirms 1) the poor quality of our target, and 2) the success of waterflooding the Queen.

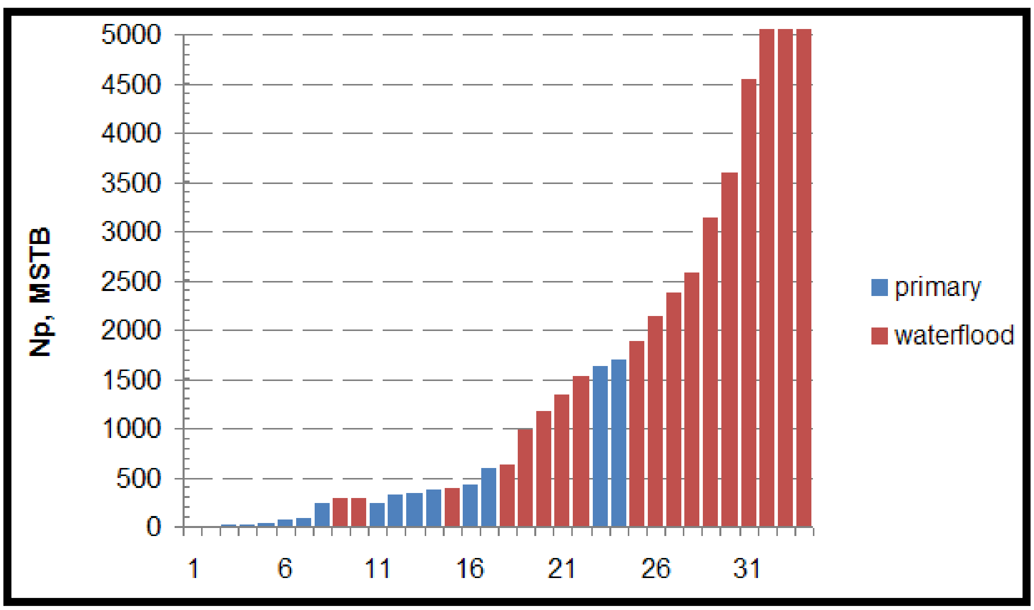

Figure 4.1 Cumulative oil production of Queen oil fields in Southeast, NM

5. Technology Transfer Efforts

Information and updates were posted on the Petroleum Engineering website of New Mexico Tech and on the RPSEA website. Also, publications and presentations were given and are listed in Appendix A.

The websites generated several requests for information; one of which resulted in further discussions on possible development of a Queen Field in Lea County, New Mexico. Noteworthy in these discussions were the issue of how to effectively stimulate the zone of interest.

6. Conclusions/Recommendations

Two wells were drilled to initiate a pilot waterflood project. A core obtained from the producer was analyzed to obtain petrophysical properties and displacement performance. The results will be coupled with improved reservoir characterization and subsequently scaled to field level using reservoir simulation to investigate various development and injection plans and prioritize with regards to oil recovery. Last, the variable mechanical properties of the Queen seen in the core and logs, and the presence of clays and fines migration, have implications on both hydraulic fracturing and water injection. For this reason, an investigation into the stimulation effectiveness of the injection well (RTQU #7) was initiated. Results will also assist the reservoir characterization and modeling efforts for this reservoir.

The failure to achieve injectivity resulted in no increase in reservoir energy or improvement in sweep efficiency; and thus no improvement in oil recovery. The prediction results from the simulation of the proposed flooding pattern showed poor performance: low oil production and water injection rates, slow flood front movement and inability to fill-up reservoir pressure. Many factors contribute to the poor performance including low permeability, high oil viscosity, depleted gas-cap and low differential pressure between bottomhole and reservoir. However, without flow and pressure data from the pilot test, the actual displacement performance cannot be modeled effectively.

The initial focus on the Round Tank was on the low pressure and temperature and unfavorable mobility ratio (low viscosity oil and no gas); both characteristic of numerous other Queen Fields in the area. However, the mechanical properties of the sand played a significantly more important role in the completion and subsequent injection and production from the Queen sand. To avoid a repeat, it is recommended to correctly characterize the reservoir, and thus properly design the stimulation treatment. As shown in this work, methods are possible using limited data to identify and describe the reservoir.

7. REFERENCES

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Kenneth G. Nolte, SPE, Amoco Production Company and Michael B. Smith, SPE, Amoco Production Company "Interpretation of Fracturing Pressures" SPE Paper 8297 Journal of Petroleum Technology, Sept 1981.

Willhite, G. P. (1986). *Waterflooding*. Richardson: SPE Textbook Series Volume 3.

LIST OF ACRONYMS AND ABBREVIATIONS

APPENDIX A

The following is a list of presentations/publications as a result of this work. The list is in chronological order.

1. Engler, T. W.: "Mini-Waterflood: A New Cost Effective Approach to Extend the Economic Life of Small, Mature Oil Reservoirs", presented at a RPSEA Progress meeting in Midland, TX (Feb 3, 2010).

2. Wilson, G.A. "Core Analysis of the Round Tank Queen Reservoir, Chaves County, New Mexico," MS thesis, New Mexico Inst. of Mining and Tech., Socorro, New Mexico, (July 2010)

3. Srichumsin, A. 2011. "Reservoir Characterization and Simulation to Assess the Waterflood Potential of The Round Tank Queen Reservoir, Chaves County, New Mexico", MS thesis, New Mexico Inst. of Mining and Tech., Socorro,New Mexico. (Feb. 2011)

4. Oduye, Oluwafemi O. and Engler, T.W.: "The Application of Pressure History Matching, Radioactive Tracers, and Temperature Logs to Analyze Hydraulic Fracture Treatments in the Queen Sand Formation, Southeastern New Mexico", presented at the SWPSC in Lubbock, Texas (April 2011)

5. Srichumsin, A. and Engler, T.W.: "Characterization of a Small, Mature Oil Reservoir with Limited Data: A Case Study of the Round Tank Queen Field", presented at the SWPSC in Lubbock, Texas (April 2011)

6. Engler, T.W.: "Failed Waterflood Effort Provides Lessons Learned", E&P Magazine (May 2011)

7. Oduye, Oluwafemi: "Analysis of the Stimulation of the Round Tank Queen Reservoir, Southeastern New Mexico ", MS Thesis, NMT, Socorro, NM (August 2011)